REVIEW AND EVALUATION OF MILL CREEK UNIT 3 AND A.B. BROWN UNIT 1 NOx DATA

PREPARED FOR:

INTERMOUNTAIN POWER PROJECT

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SECTION 1.0

INTRODUCTION

In a July 6, 1983 meeting, representatives of the Utah Department of Health (DOH) suggested that the boilers at the Intermountain Generating Station (IGS) might be capable of achieving an emission limit for NOx of 0.50 lb/MBtu. In suggesting this limit, DOH was relying (1) on the fact that some power plants had recently been permitted at or below an emission level of 0.50 lb/MBtu; and (2) on EPA reports (Refs. 1 and 2) containing information on bituminous coal-fired utility boilers owned by Louisville Gas and Electric Company (LG&E) and Southern Indiana Electric and Gas Company (SIEGCO) which exhibited NOx emissions at or below the 0.50 lb/MBtu level on a 30-day average.

The purpose of this report is to address the questions raised by the DOH in the July 6, 1983, meeting. Section 2.0 of the report briefly describes the IGS boiler design and some of the factors that influenced the design; it then responds to the DOH's observations concerning recently issued permits with NOx limits less than 0.55 lb/MBtu. Section 3.0 describes and evaluates NOx data from EPA tests on LG&E's Mill Creek Unit 3 (Ref. 1). Section 4.0 describes and evaluates NOx data from EPA tests on SIGECO's A. B. Brown Unit 1 (Ref. 2). Section 5.0 draws conclusions from these evaluations based on the appropriateness of an NOx emission limit less than 0.550 lb/MBtu for the IGS boilers. This report relies in part on data presented in a more detailed report entitled "Technical Evaluation of Alternative NOx Control Strategies," (Ref. 3), which was submitted to the Utah DOH in June 1983. The purpose of that report was to respond to questions concerning the feasibility of using five control technologies in addition to the existing low-NOx boiler/burner design at IGS.

SECTION 2.0

INFLUENCING FACTORS FOR THE IGS DESIGN

The design of a boiler to meet stringent NOx limitations must consider a number of important factors. Among these are the coal type, load schedule, and the availability and reliability of the boilers. As mentioned in Reference 3, the IGS boilers were designed to fire high slagging Utah bituminous coal in a high base-load condition. Significant efforts were expended to ensure that the units would have high reliability and availability.

The coal selected by IPP is classified as a bituminous coal. EPA recognized the distinction between bituminous and subbituminous coals when they established the 1979 NSPS for NOx in that they set different levels of NOx limitations for these coals; i.e., 0.60 lb/MBtu for bituminous and 0.5 lb/MBtu for subbituminous coal. As mentioned in Reference 3, these different limitations were established as a result of EPA's concerns for adverse side effects with bituminous coals. The Utah DOH has expressed the opinion that because eight utility boilers have recently been permitted at levels at or below 0.50 lb/MBtu for NOx, the present design for IPP should be able to achieve a limitation of 0.5. It should be made clear that the eight units mentioned by the DOH all fire <u>subbituminous</u> coal. No utility boilers firing bituminous coals have been permitted at the level of 0.5 lb/MBtu or lower. The 0.550 lb/MBtu limitation provided in the IPP Permit to Construct is the most stringent limitation for bituminous coal in the country. B&W took this into account when designing the IGS units (Ref. 3).

Other coal-related factors that influence the design of the boiler are associated with the ash, moisture, and slagging potential of the coals to be burned. B&W has indicated that with the characteristics of the Utah bituminous coal, they could not guarantee levels below the 0.550 lb/MBtu NOx level for the IGS boiler design. One aspect of the design is related to the burner zone heat release rate (Btu/sq.ft-hr). The smaller this value, generally the lower the NOx emissions with all other conditions being constant. Due to the high slagging potential of the IPP bituminous coal, B&W could not take advantage of techniques such as addition of burner zone division walls in order to decrease the heat release rate. The IGS boilers were designed with the smallest practical burner zone heat release rate for the coal to be burned for IPP. If subbituminous coal had been the design coal for IPP rather than Utah bituminous coal, the boiler design would have been different and consequently a NOx limitation of 0.5 lb/MBtu would have been appropriate.

Another important factor related to the ability of a boiler to achieve low NOx levels on a 30-day rolling average basis is dependent on the design load schedule and the NOx emission rate vs. load characteristics. If, for example, NOx increases with increasing load at a unit which is designed to cycle between high and low loads over a 30-day period, that unit will exhibit 30-day rolling average NOx levels less than the maximum instantaneous NOx emission level. The design of the unit would then not be as critical with regard to high load NOx emissions; i.e., lower low load NOx emissions could be used to offset high emissions at the maximum load conditions. On the other hand, if the unit is designed to operate at high loads in a base load condition, this offset is not possible. The 30-day rolling average NOx and the maximum instantaneous NOx levels would coincide. The design of a base loaded unit therefore must be more conservative such that the instantaneous emissions not exceed the maximum 30-day NOx emission level. The IGS units were designed for the base loaded condition where the unit could operate at near full load for prolonged periods of time. This, coupled with the design for high reliability and availability, leaves virtually no margin in the design to achieve maximum load NOx emissions significantly below the permitted 0.550 lb/MBtu limit.

As will be shown in the following sections, the LG&E Mill Creek Unit 3 and the SIGECO A. B. Brown Unit 1 boilers operate in the cycling mode and incorporate design features which are not compatible with the IGS units. They therefore exhibit lower 30-day average NOx levels which would not be achievable on the IGS units.

SECTION 3.0

MILL CREEK UNIT 3 NOx DATA EVALUATION

3.1 EPA PROGRAM DESCRIPTION

The objective of the EPA-sponsored program on LG&E Mill Creek Unit 3 was basically to determine if operation of a boiler with low-NOx characteristics exacerbated corrosion in utility boilers. Reference 1, prepared by Exxon, contains information on this program performed on a Babcock & Wilcox boiler equipped with 40 low-NOx B&W dual register burners. The boiler was designed to meet the 1971 New Source Performance Standards (NSPS) for NOx of 0.7 lb/MBtu, but generally operated in the range of 0.56-0.46 lb/MBtu on a 24-hour average basis. It should be pointed out that the Exxon report is only a preliminary draft for EPA review. Before it becomes final, the report must undergo a thorough peer review, which could result in significant changes in both content and conclusions.

The test program had four major objectives:

1. Characterization of the boiler in its normal operating mode and in modified modes designed to control NOx without causing short-term adverse effects.

2. Evaluation of the effects of boiler operation on tube metal corrosion using a corrosion probe technique for periods of 30, 300, and 1000 hours. In addition, ultrasonic measurements of corrosion panels were made after a 15,000 hour period.

3. Environmental assessment testing of major streams entering and leaving the boiler.

4. Determination of NOx emissions for two 30-day periods during the corrosion test period.

The program objectives of relevance to establishing an NOx limitation are the characterization, corrosion, and 30-day NOx tests. These three phases of the EPA program will be evaluated in the following paragraphs in terms of the appropriateness of the use of the data for establishing an NOx limitation which is lower than 0.550 lb/MBtu for the IGS.

3.2 BOILER CHARACTERIZATION

Mill Creek Unit 3 fires bituminous coal with a sulfur content of 3% to 4%. Coal analyses in Exxon's report showed the coal to have medium slagging tendencies and low fouling tendencies on a four-point scale from low to severe. Data presented in the report indicated that the boiler is a 400 MW B&W boiler with 40 B&W dual-register burners fed by four mills. Information from Reference 4 showed the boiler in fact to have a rated capacity of 425 MW.

During Exxon's characterization phase of the program, 49 short-duration tests were performed to evaluate additional modifications to the operation to achieve further NOx reductions. The data summary for these tests is shown in Appendix A. These combustion modifications were:

1. Amount of excess air
2. Fuel/air bias and distribution among the 40 burners
3. Flame shaping by burner vane adjustment
4. Flue gas recirculation (FGR) to the burner hopper
5. Firing patterns with mills out of service
6. Load reductions

Exxon concluded that load reductions and firing patterns using various mills out of service were not practical NOx reduction techniques due to operational considerations. The following was concluded about the other four NOx reduction methods:

1. Reduction of excess O_2 from 4% to 3% would result in a NOx reduction of 40 ppm. Normal boiler operation was at the 5% level.

2. Fuel biasing (fuel lean at the top burners, fuel rich at the bottom burners) resulted in a 15% decrease in NOx. Exxon recommended that the boiler be operated in this condition "whenever operational conditions allowed".

3. Flame shaping with burner vane adjustments affected the flame stability. The settings should be made for best overall operation over the load range, and then fixed in this position. An outer vane setting of 50% open was recommended. The variation in NOx with acceptable settings was 10%.

4. Flue gas recirculation (FGR) to the hopper reduced the NOx emissions by 12% at full load. The configuration tested only allowed FGR for steam temperature control and was not recommended for NOx control.

Exxon finally concluded that the "as-found" full load NOx emission averaged 0.54 lb/MBtu for six tests. They then concluded that reducing the excess air and biasing the air would allow emissions to be reduced to 0.49 lb/MBtu based on five test conditions (Tests 4, 6, 8, 30, and 31--Appendix A). Exxon recommended that the boiler be operated in the biased mode "whenever conditions allowed" and that the excess oxygen should be decreased to levels no lower than 3.0% to 3.5% if a CO monitor were not in use.

Although Exxon stated the foregoing conclusions in its preliminary report--a report which has not been reviewed--careful examination of the test data presented in that report and other supporting documentation leads to the conclusion that Exxon's recommendations are either not applicable to IPP or have no scientific foundation. The following paragraphs will discuss the information available to Exxon to draw conclusions regarding alternate operating modes to reduce NOx emissions. This discussion will show that:

1. Insufficient data was gathered to make conclusions.
2. Baseline conditions were not established.
3. The proposed alternate operating mode was not tested.
4. Long-term tests were not performed.
5. Minimal operating guidelines were established, but were not determined on a sound scientific basis.

Exxon described its normal test procedure for evaluating the various additional combustion techniques for reducing NOx emissions, stating "Each such test required about an hour." Included in the 49 tests were evaluations of 15 separate parameters; consequently, few tests could be performed on any one set of conditions as can be seen from Table A-1 in Appendix A. With 15 parameters to evaluate, the use of 49 tests is not sufficient to establish statistical significance of any one parameter. Few comparison data points would be available from which to evaluate any one parameter with only 49 tests.

Exxon recommended that the boiler be fired at low excess oxygen levels using biased firing with outer burner air registers set at 50% open. Very few data points were available from which to draw this conclusion. For example, Table 3-1 shows the pertinent data available to Exxon to arrive at the conclusion that the recommended mode would allow the boiler to achieve NOx emission levels 15% below the normal operating mode. The data in this table are grouped with respect to outer burner air register (vane) opening, and represent conditions at normal excess oxygen levels without biasing (Tests 3, 5, 28, 39, and 42) compared to data at lower excess oxygen with biasing (Tests 4, 6, 30, and 31). The following paragraphs will describe in detail the fact that some of these data (Tests 4, 6, and 42) are not valid for comparison purposes.

TABLE 3-1. MILL CREEK UNIT 3 SUPPORTING DATA FOR EXXON RECOMMENDED OPERATING MODE

Test No.	Load MWe	FGR*	O_2,%	Burner Register Setting: Inner % Open	Burner Register Setting: Outer % Open	Fuel Pattern*	Air Bias*	NO, ppm at 3% O_2
5	385	None	3.61	36	36	50	0	346
28	409	None	4.41	36	36	50	0	408
42	410	None	4.52	44†	29	50	0	463
6	387	Low	2.81§	36	36	60	6	343
31	404	None	3.43	36	36	60	6	373
3	389	Low	3.70	36	51	50	0	337
4	385	Low	2.77§	36	51	100#	6	313
29	408	None	3.96	36	71	50	0	402
30	404	None	3.58	36	71	60	6	392

*See Appendix A, Table A-1 for units.

†Inner burner air register adjusted.

§Excess oxygen below 3.0% and no FGR comparison point.

#Fuel to upper burners terminated.

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In order to establish a scientifically sound alternative operating mode, the data base must define the normal (or baseline) operating conditions, and develop directly comparable data for the alternative operating modes. At no point in the Exxon report were the exact normal operating conditions defined, however. It was mentioned that movement of the burner registers to achieve low NOx levels at varying loads was impractical, yet their definition of "as-found" conditions (Tests 3, 5, 27, 28, 29, 42) contained data at four combinations of inner and outer register settings as well as two FGR rates. A baseline condition from which to compare the effects of combined NOx reductions was never clearly established, therefore the exact degree of reduction in the recommended mode cannot be ascertained.

It was recommended that a fixed setting of outer burner air register position be set at 50% open, which they alluded to as being the manufacturer's recommended position. No mention was made of the effect of inner register setting; however, examination of the data showed that changing the setting from 36% open to 44% open and reducing the outer register from 35% to 29% open resulted in average NO emissions from nine tests (Tests 40 through 49) of 503 ppm. This is 130 ppm, or 35%, higher than any of the other "as-found" test conditions with an inner register setting of 36% open. By far, this one parameter appears to be the most significant and was never mentioned. Presumably, the 36% open position was the normal setting, since most of the tests were performed at that condition, As a consequence of this, Test 42 in Table 3-1 should not be used in determining the percentage reduction with biased firing since this 44% open setting had such a detrimental effect on NOx emissions.

Other serious discrepancies exist with the data. The recommended level of excess oxygen was between 3% and 3.5%. Two of the data points (Tests 4 and 6) in Table 3-1 were below this level, and other parameters were changed, affecting the NOx interpretations. For instance, Test 6 was performed with FGR, while other tests at the 36% outer register setting used no FGR. It is therefore questionable whether this point should be used since there is no comparison point in the "as-found" operating mode. Similarly, Test 4 was operated with a fuel pattern of 100 (see Appendix A) in the biased mode, while other biased tests (Tests 6, 30, and 31) were at a pattern of 60.

A fuel pattern of 100 represents no fuel to the top row of burners. This configuration was not recommended by Exxon. Operation in this condition could severely limit the boiler load due to exceeding the coal mill design throughput. In addition, Test 4 was performed at 82% of the rated load of the boiler which would be expected to result in a NOx reduction. This data point does not represent a valid biased firing configuration and should also be excluded from the comparison.

Probably the most significant flaw in the Exxon recommendations is that there were no data collected showing boiler operation in the condition recommended by Exxon; i.e., low excess air operation no lower than 3.0% O_2 with burner outer registers at 50% open and fuel to all burner elevations. Nevertheless, some data points might be said to suggest that the recommended configuration would reduce NOx emissions. Depending on how these data are used, significantly different conclusions can be drawn. Generally, Exxon averaged data at presumably similar conditions and compared these averages to draw conclusions about the effectiveness of NOx reduction techniques. If Tests 4, 6, and 42 are excluded from the comparisons for the reasons stated previously, then Tests 3, 5, 28, and 29 would be considered as valid "as-found" conditions, and Tests 30 and 31 as valid low excess air biased firing conditions. Comparing the averages of data from these two conditions, the conclusion would be reached that, on the average, there is a net <u>increase</u> in NOx emissions of 10 ppm (373 compared to 383 ppm), or a 2.7% increase. If on the other hand the maximum NOx emission in the "as-found" condition (Test 28, 408 ppm) was compared to the minimum emission in the biased firing condition (Test 31, 373 ppm), the result would be a 35 ppm (8.6%) decrease in NOx emissions. In any event, neither result using either the averaged data or the maximum vs. minimum data should be considered valid due to their lack of statistical significance. Using either average or maximum compared to minimum data, neither the 2.6% increase nor the 8.6% decrease in emissions is within the accuracy of the Mill Creek monitoring devices. In addition, the use of only two data points to compare maximum and minimum NOx emissions with a resulting 35 ppm (8.6%) decrease would not be considered adequate to demonstrate a long-term trend.

The type of testing performed by Exxon could at best be considered as screening tests to establish the probable potential for various combustion modifications. Operation of a promising mode for a few hours at one load could not possibly establish the validity of a technique over the load range under the varying coal supply conditions and normal day-to-day variations in boiler operation. Normally, before recommending a mode of operation that is so drastically different from normal boiler operating practice, an extensive test program lasting as long as several months would be required. Good engineering practice would dictate a thorough evaluation of all of the potential long-term adverse side effects that might result from a significantly different operating mode.

An example of one long-term adverse side effect that could accompany the Exxon proposed mode of operation would be severe slagging, particularly with a high slagging coal such as used by IPP. Exxon stated in its report that one criterion used to determine the lower limit of NOx control was visual observation of the slagging during the short tests. It should be pointed out that slagging is a phenomenon that generally develops over a period of days or weeks before the severity of the condition becomes apparent. Several hours of operation could be performed at conditions that would be unacceptable for long-term operation. The changes in slagging characteristics during the short-term (one hour) testing performed by Exxon would most likely be imperceptible to the observer. Indications of incomplete combustion, such as CO, might however be a method of detecting incipient slagging during short-term testing.

Good boiler operating practice is to clearly define an alternate operating mode through extensive testing and to define modifications to that mode during upset conditions. In Exxon's report, neither of these conditions was satisifed. Operating conditions were recommended based upon inferred results from tests lasting only one hour. Only one operational procedure was specifically mentioned with regard to minimum excess oxygen levels. In their conclusion, Exxon recommended that excess oxygen be reduced to no more than 3.0% to 3.5% when a CO monitor was not in use. It is unclear why this level was chosen other than the fact that CO was present in the economizer region at excess oxygen levels below this level. CO in a coal-fired boiler certainly would be an indicator of potential slagging if the measurements were made in the proper region of the boiler. No data presently exist in the literature that would suggest that monitoring CO in the backpass of the boiler (economizer) would indicate incipient slagging. As explained in Reference 3, locally reducing atmospheres in the furnace can exacerbate slagging characteristics. These local reducing regions might be detected by high CO levels in the furnace. Other regions in the furnace, which by necessity must be oxidizing, mix with the locally reducing regions before the flue gas products enter the convective section (superheat, reheat, and economizer regions) of the boiler. Consequently, CO generated in the furnace will react with the oxygen in these oxidizing regions and complete combustion prior to entering the economizer. As a result of this, slagging conditions could be present in the furnace at excess oxygen levels in the economizer which are well above the level where CO appears in the economizer. Therefore, determining the minimum excess oxygen level using economizer CO as the trigger would not necessarily indicate when slagging could occur. Only <u>long-term</u> tests at elevated economizer CO levels would indicate whether the CO in that region was an important parameter to measure. The proper region for CO measurement would be the furnace itself; however, temperatures in this region preclude its measurement on a routine basis.

Operation of the IGS boilers at excessively low excess oxygen levels could result in severe slagging. The IPP coals have higher slagging indices than does the Mill Creek coal. The IGS boilers are designed to operate at relatively low excess oxygen levels in the range of 4%. The actual operating excess oxygen level, however, will be determined after months of operating experience and will take into account the effects on slagging, carbon carryover, steam temperature requirements, and efficiency, as well as NOx emissions. An arbitrary requirement to operate at excess oxygen levels lower than the practical level could have dire consequences due in part to increased slagging. The increased slagging would ultimately affect the reliability and availability of the boilers. Slagging conditions are generally remedied by one or more corrective measures including increased excess oxygen, reduced load operation, and frequently bringing the boiler off line to jackhammer or dynamite the slag out of the furnace. Some of these remedies not only affect the reliability of the boiler, but also may increase the NOx emissions.

3.3 CORROSION TESTING

The major objective of Exxon's program was to determine if corrosion resulted from operation of a boiler at low NOx levels. These corrosion tests were performed shortly after testing was completed to evaluate alternate methods for reducing NOx emissions. The Exxon report did not make it clear that the additional methods of decreasing NOx evaluated during the characterization tests and discussed previously were not used during the corrosion tests. The boiler was operated in its normal mode at the boiler operator's discretion. The original design of the B&W boiler and burner was dictated by the necessity to limit corrosion and slagging. One of the driving forces behind the development of the low-NOx burner was to eliminate the environments that were conducive to these adverse effects.

It is therefore not surprising that the corrosion was not excessive after 15,000 hours of boiler operation. Exxon reported averages of corrosion levels at a number of points in the boiler. The significant corrosion rate, however, would be the highest rate at a particular location since that would determine the minimum failure time and the location of the failure. The maximum corrosion rates were above the burner zone as might be expected. Even at this point, the failure rate nevertheless seemed not to be excessive.

The apparent lack of excessive corrosion on the Mill Creek unit does not necessarily indicate the lack of this potential on the IPP units. The potential would be increased on the IGS units if any of the alternate techniques suggested by Exxon were to be implemented. In addition, it should be pointed out that the Mill Creek units operate at levels above the 0.550 lb/MBtu limit for NOx when the load schedule approximates the base load conditions of the IPP units; i.e., loads of 95% or greater for long periods of time.

3.4 NOx 30-DAY CHARACTERIZATION

As part of the Exxon program, testing was performed to determine 30-day rolling average NOx levels during two separate time periods during the corrosion testing. KVB was subcontracted by Exxon to perform these 30-day tests. During these tests, the boiler was operated in the normal operating mode. None of the alternative NOx control methods discussed in Section 3.2 were used during these tests.

As mentioned in Section 2.0, utility boilers can operate in a number of load schedule modes. Mill Creek Unit 3 operated in a cycling or swing mode during the two continuous monitoring test periods. Table 3-2 shows the data for 36 consecutive days of testing at 24-hour average loads varying from 24% (101 MW) to 87% (371 MW) of full load. During the 36-day period, the load averaged 68% (129 MW) of full load, with a 30-day rolling average NOx level of 0.51 lb/MBtu. This is illustrated in Figure 3-1. Reference 4 describes in detail the 30-day test results for the Mill Creek unit. Figure 3-2 provides data from this reference that shows the NOx vs. load characteristics of Mill Creek Unit 3 for 1225 of the hourly average data points collected during the test program. As can be seen from the figure, the NOx increases with increasing load. It would therefore be expected that a load schedule composed of higher loads on the average over a 30-day period would exhibit higher 30-day average NOx emissions levels than were presented in the Exxon report (Ref. 1).

The cycling load schedule of the Mill Creek unit is not the design load schedule for the IGS units. The IGS units were designed to operate at base load conditions near full load for extended periods of time. Data presented in Reference 5 allowed extraction of 198 hourly average NOx and load data points which were between 92% (392 MW) and 100% (425 MW) of full load. These data points represent the tenth data cell used in the analysis presented in Reference 4 and are included in Appendix B (Table B-1). From these data, a high load scenario similar to that of the IGS units can be generated. Assuming that the data points represent 198 consecutive hours of operation, or 8 days and 6 hours, 30 days of data can be generated by cycling through the data 3.64 (720/198) times. This generates 30 days of data (Appendix B, Table B-2) using no two days containing the same hourly averages. Figures 3-3 and 3-4 show NO and O_2 characteristics for the first 24 hours of data generated in this manner. During the first simulated day, the load varied between 92% and 100% of rated load, while the hourly NOx levels varied between 0.48 and 0.63 lb/MBtu. Figure 3-5 shows the simulated daily average plotted in the same

TABLE 3-2. SUMMARY OF DAILY AVERAGE EMISSIONS AND OPERATING DATA
MILL CREEK UNIT 3, TEST 2 (Ref. 1)

			24-HOUR DATA DRY STACK GAS CONCENTRATION*						
Date 1981	Elec Load MW_e	Therm Load MW_{th}	O_2 Vol%	CO_2 Vol%	CO PPMV 3% O_2	NO PPMV 3% O_2	CO ng/J	NO ng/J	NO lb/MBtu
2/26	331	571.2	5.3	13	-	341	-	200	0.47
2/27	223	417.9	7.5	10.4	-	354	-	208	0.48
3/2**	316	718.1	4.5	13.4	-	406	3	238	0.55
3/3	323	602.4	4.8	14	28	371	10	217	0.5
3/4	366	694.9	4.2	13.6	33	364	11	214	0.5
3/23***	332	692.6	4.3	12.6	28	382	10	224	0.52
3/24	296	555.9	5.3	13.5	25	352	9	206	0.48
3/25	305	566.4	5.8	11.8	30	359	11	210	0.49
3/26	300	529.1	6.2	11.5	32	395	11	232	0.54
3/27	200	309.9	8.3	9.5	49	367	17	215	0.5
3/30	305	574.8	6	12.2	-	377	-	221	0.51
3/31	323	605.5	5.2	12.6	30	377	11	221	0.51
4/1	327	614.6	5.4	12.2	42	373	15	219	0.51
4/2	325	609.9	5.9	11.7	39	381	14	223	0.52
4/3	188	345.4	8.8	8.8	50	350	17	205	0.48
4/4	102	207.3	11.7	4.9	105	319	37	187	0.43
4/5	101	209.8	12	4.9	114	328	41	192	0.45
4/6	238	446.3	7.7	9.7	51	375	18	220	0.51
4/7	248	460.2	6.3	11.2	44	355	15	208	0.48
4/8	263	483.1	6.3	11.1	50	352	17	206	0.48
4/9	322	605.3	5.9	11.8	48	396	17	232	0.54
4/10	325	609	5.2	12.5	47	372	17	218	0.51
4/11	194	396.9	5.2	12.3	69	354	24	208	0.48
4/12	252	467.3	6.1	11.5	58	350	20	205	0.48
4/13	263	495.9	6.4	11.1	72	356	26	209	0.49
4/14	358	680.5	5.1	12.4	78	409	27	240	0.56
4/15	350	669.3	5.6	12.1	-	416	-	244	0.57
4/16	356	681.2	4.9	12.4	33	397	12	233	0.54
4/17	359	690.5	5	12.4	29	391	10	230	0.53
4/18	267	509.2	7.4	10.1	54	400	19	235	0.55
4/19	298	556.9	5.7	12	39	387	14	227	0.53
4/20	350	683	6.1	11.9	54	383	19	225	0.52
4/21	349	660	5.4	12.7	58	411	21	241	0.56
4/22	359	664	4.8	12.7	52	408	18	239	0.56
4/23	353	662.5	5	12.5	44	401	16	235	0.55
4/24	371	651.3	4.9	12.7	79	413	28	242	0.56

* Dashes indicate "No Data."
** February 28 and March 1: Plant Shut-down for maintenance.
***March 5 to March 26: Labor strike.

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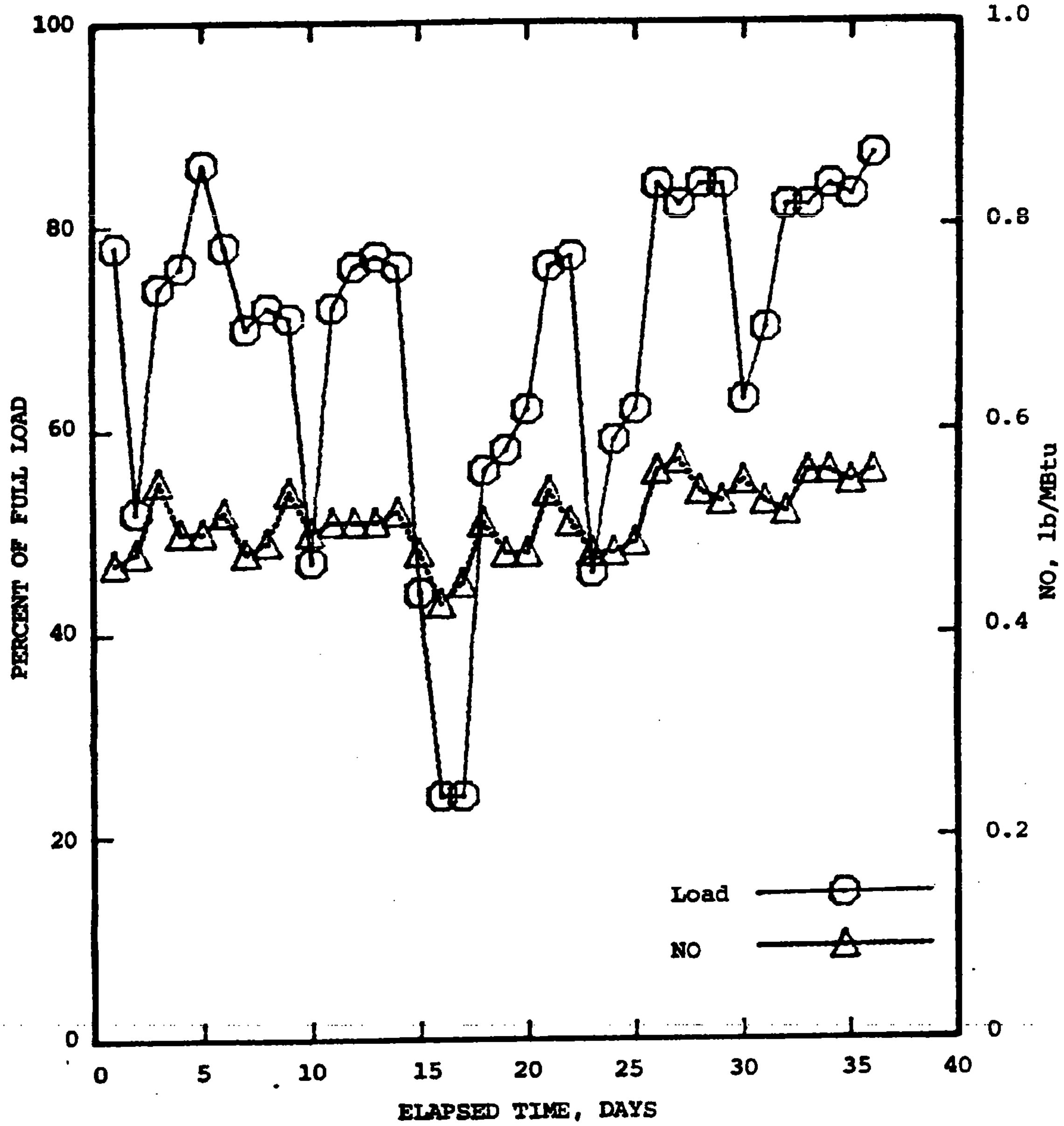

Figure 3-1. Mill Creek Unit 3, 30-day NOx data (Ref. 1).

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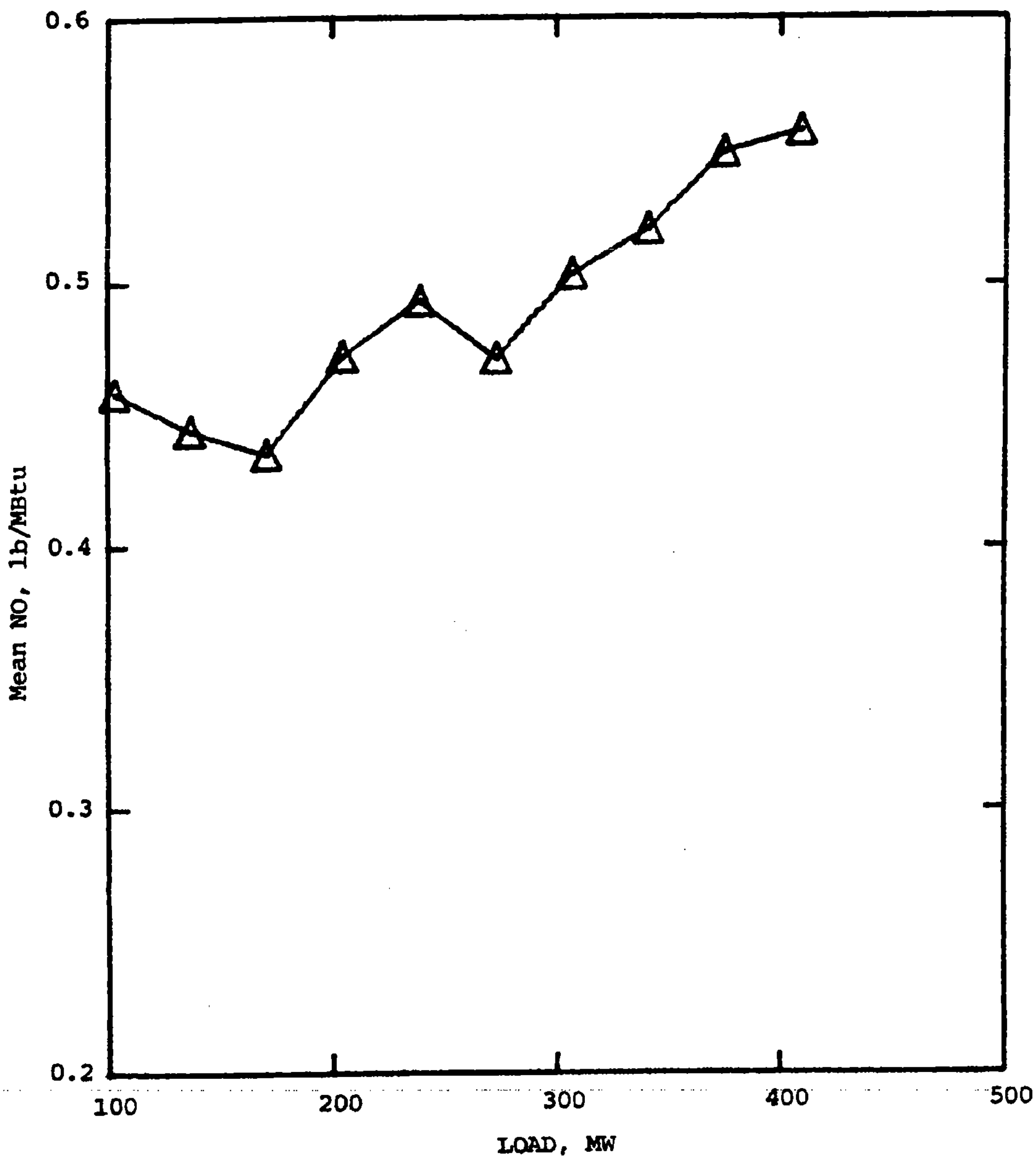

Figure 3-2. Mill Creek Unit 3 boiler NOx characteristics.

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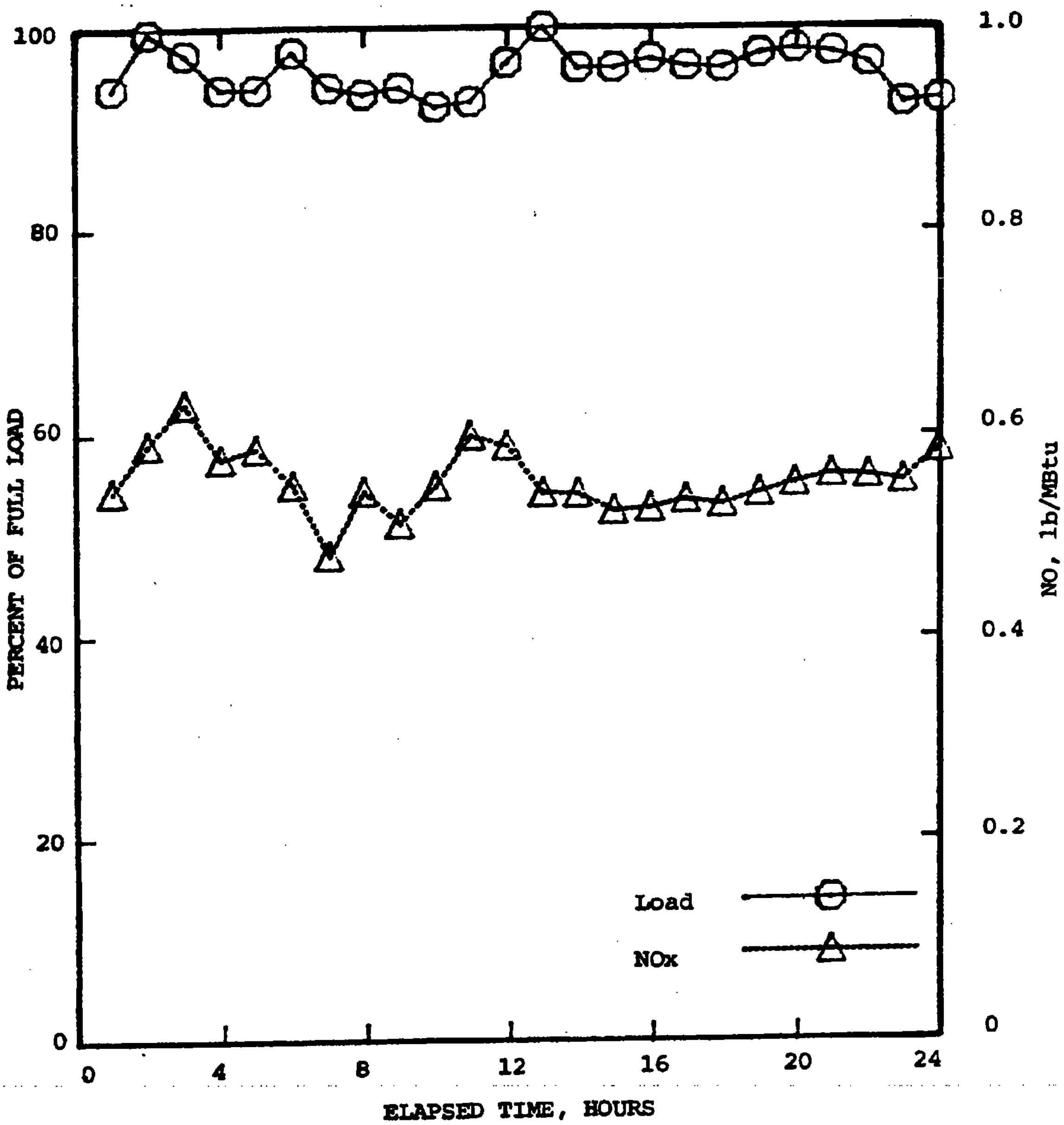

Figure 3-3. Mill Creek Unit 3, high load scenario, one day hourly average NOx (Ref. 5).

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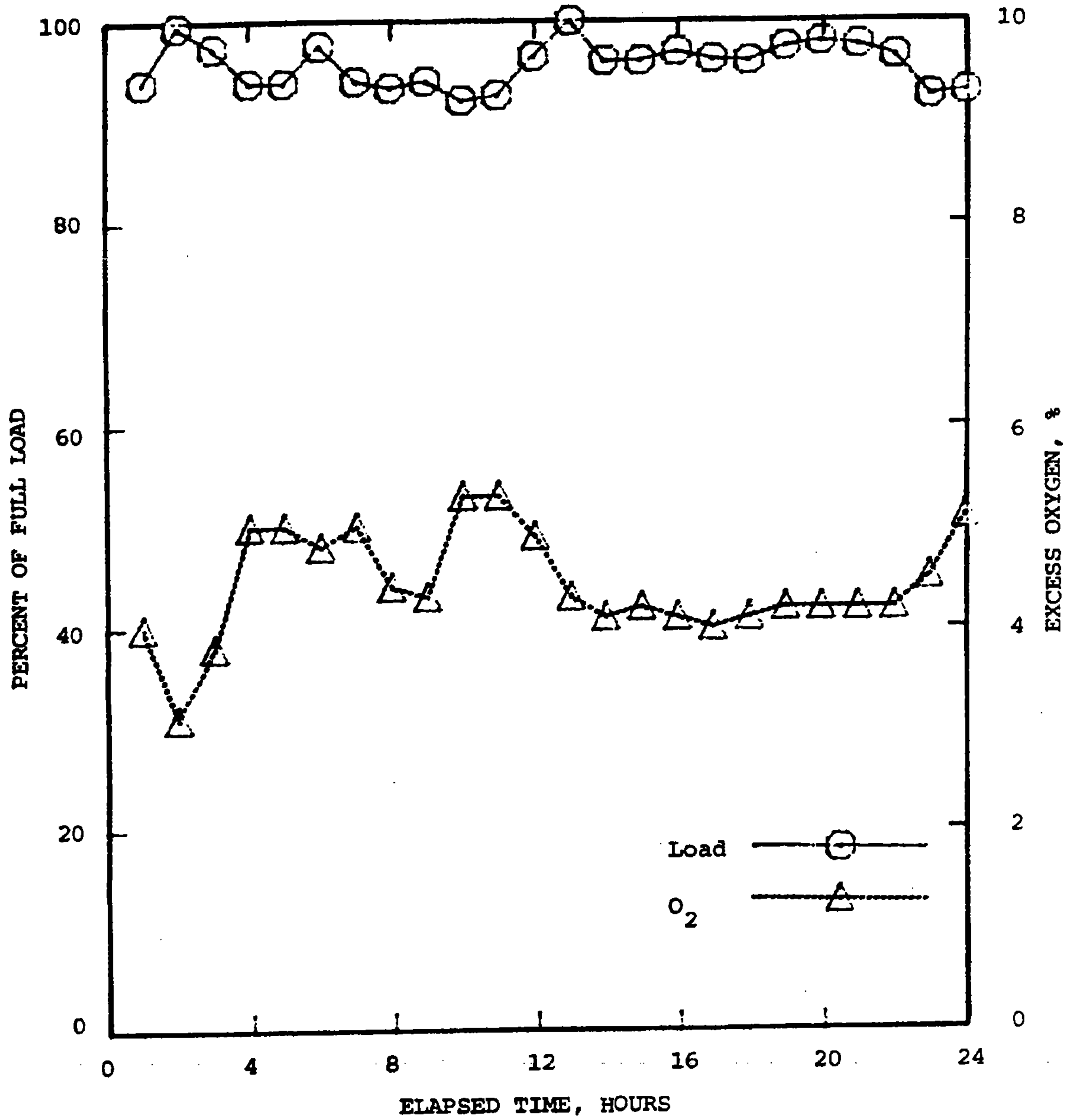

Figure 3-4. Mill Creek Unit 3, high load scenario, one day hourly average O_2 (Ref. 5).

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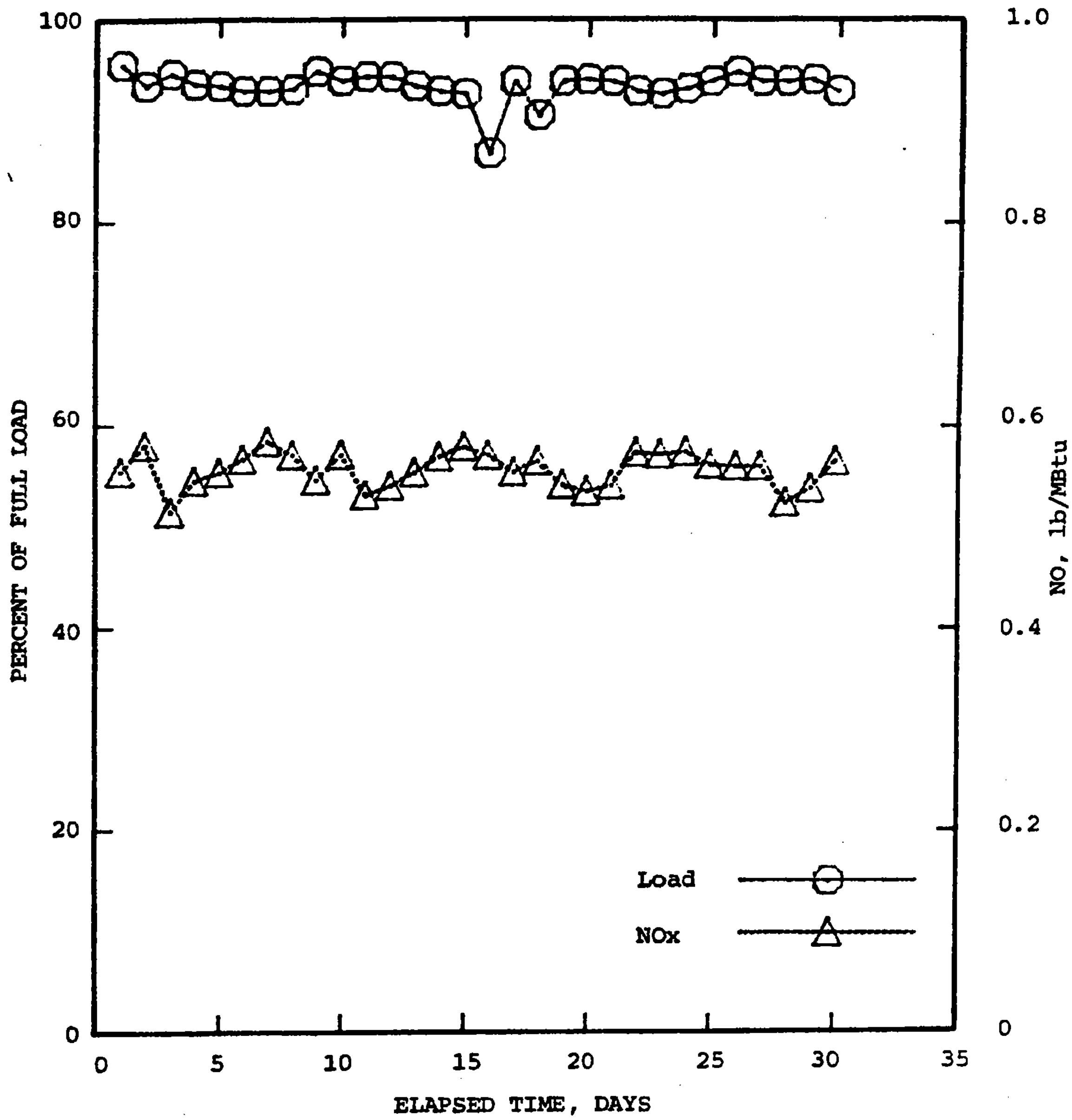

Figure 3-5. Mill Creek Unit 3, high load scenario, NOx characteristics, 30-day NOx data (Ref. 5).

manner as the Mill Creek data (Fig. 3-1). The average load for this scenario is 93% of full load with a 30-day rolling average NOx level of 0.56 lb/MBtu. This scenario more closely represents the load schedule of the IGS units. Of particular importance is the fact that the 30-day rolling average NOx did in fact increase as the average boiler load increased above that (68%) shown for Mill Creek Unit 3. In addition, rather than showing the IPP units could meet a 30-day limit lower than 0.55 lb/MBtu, the data suggest that Mill Creek Unit 3 itself might not meet the 0.55 lb/MBtu limit under high base load conditions.

The base loaded scenario presented in Figure 3-5 is not an atypical load schedule. Reference 4 shows data from a base loaded 680 MW B&W unit operated by Pennsylvania Electric (Homer City Unit 3). This unit also incorporates the B&W low-NOx dual register burners and fires bituminous coal with a sulfur content of 2%. Figure 3-6 shows the load and NOx characteristics of a 36-day period while the unit was operating at near full load. The 30-day rolling average NOx level during this period was 0.65 lb/MBtu. An important point concerning both this data and the data for the Mill Creek unit is that the NOx measurements were made by EPA protocol certified NOx monitors.

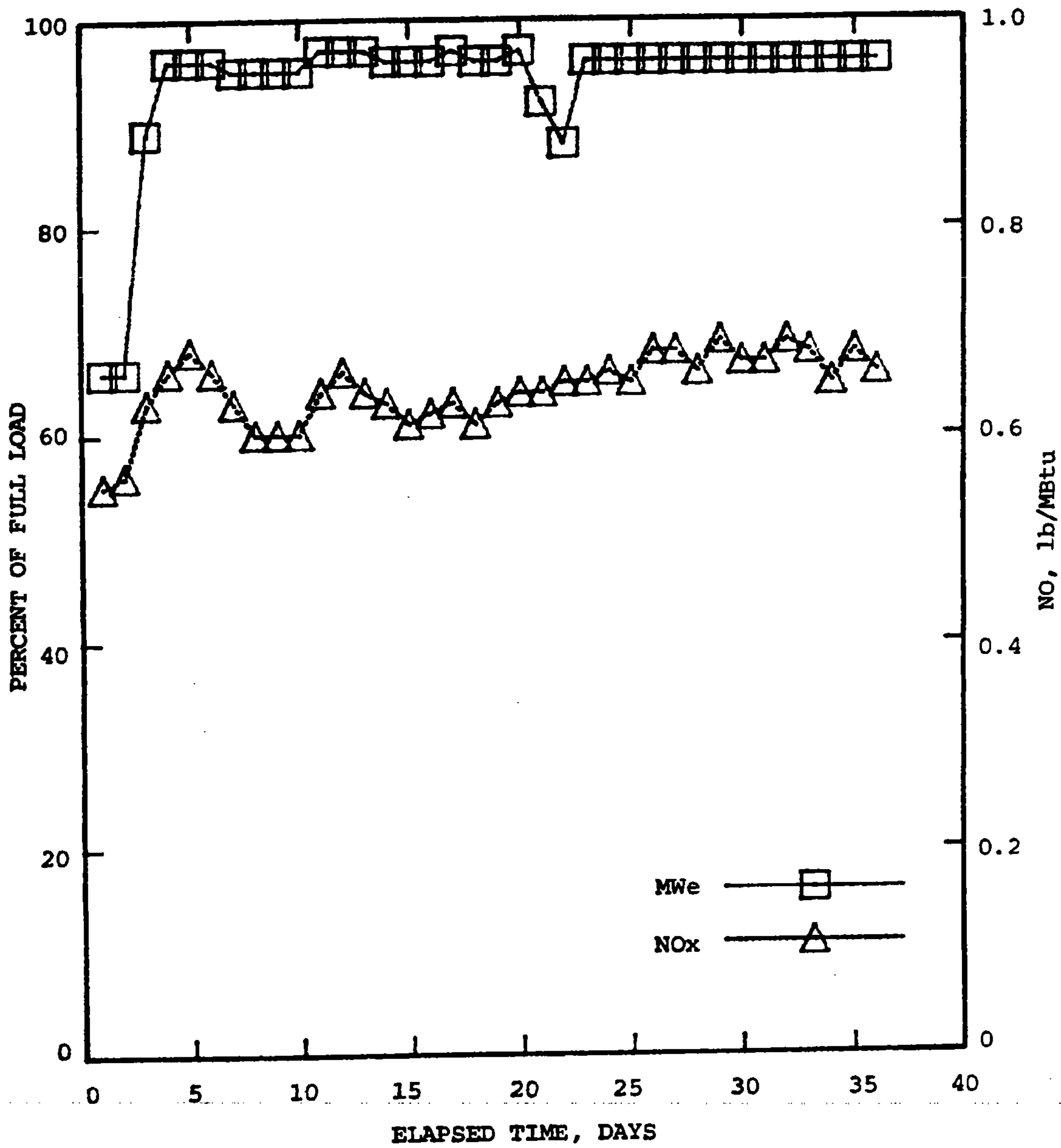

Figure 3-6. Homer City Unit 3, base loaded, 30-day NOx data (Ref. 4).

SECTION 4.0

A. B. BROWN UNIT 1 NOx DATA EVALUATION

4.1 EPA PROGRAM DESCRIPTION

The objective of the EPA-sponsored program on the Southern Indiana Gas and Electric Co. (SIGECO) A. B. Brown Unit 1 was to document the performance of SO_2 collection equipment and NOx emissions from a Babcock & Wilcox boiler. The NOx emission levels obtained from 68 days of continuous data were collected and used to determine the 30-day NOx averages. Similarly, continuous SO_2 data were collected to determine the 30-day SO_2 averages. GCA Corporation prepared five volumes (Ref. 2) describing the program results and presenting the data for both the SO_2 and NOx data. Only those portions of the final report which discuss findings with respect to NOx emissions will be discussed in the following paragraphs. As with the Mill Creek report discussed in Section 3.0, the A. B. Brown final report is only a preliminary draft for EPA review. It has not undergone the normal EPA peer review prior to final issuance.

4.2 NOx 30-DAY CHARACTERIZATION

A. B. Brown Unit 1 is a 265 MW B&W boiler designed to fire bituminous coal with 2.0% sulfur content. Two significant differences exist between this boiler and the IGS units: (1) boiler furnace design and (2) load schedule. Both of these factors significantly affect the NOx levels achieved during the EPA test program. Other data relating to the accuracy of the NOx data also affect the validity of the NOx measurements during the 68-day test period.

Generally speaking, boilers with small heat release rates (Btu/sq.ft-hr) in the burner zone have low NOx emission levels with all other factors being equal. There are constraints on designing boilers with extremely small heat release rates, however. One of these constraints has to do with the slagging tendency of the coal used in the boiler; another constraint is the physical size of the boiler itself. One method of reducing the burner zone heat release rate is to add furnace division walls in the burner zone. The A. B. Brown unit incorporates such division walls in this region. The size of the unit and the low slagging coal permits use of these division walls since slag buildup and removal is not a problem. The IGS units, on the other hand, use high slagging Utah coals which, according to B&W, preclude the use of division walls in these units. As a result, the A. B. Brown unit has a smaller heat release rate than do the IGS units. The NOx levels might therefore be expected to be lower on the A. B. Brown unit. Without the division walls, however, the A. B. Brown heat release would be almost identical to that of the IGS units.

As mentioned in Sections 2.0 and 3.0, the load schedule for a boiler plays a significant role in the 30-day average NOx emissions. The A. B. Brown unit is the last unit to be dispatched and the first to reduce load in the Pennsylvania Electric System. In addition to the restrictive load schedule, the unit experienced other load reductions during the test program associated with mill outages. The net result is that the unit varied in load from approximately 25% to 80% of full load during the program. Again, this is not the high base load condition of the IGS units. Figure 4-1 shows the load schedule and the resulting daily average NOx levels measured during the test program. The 30-day average NOx level was 0.39 lb/MBtu at an average load of 50%. As mentioned previously, the low level of NOx could be due to the low burner zone heat release rate.

One of the most significant problems with the A. B. Brown NOx data was that it was not collected with an EPA certified NOx monitor. Table 4-1 shows a comparison of the certification parameters from the A. B. Brown unit and the Mill Creek and Homer City units. Of the seven significant certification criteria, the NOx instrument on the A. B. Brown unit only passed one. Two parameters were not measured and three failed completely. Of the three parameters that failed, the most important was the relative accuracy test. GCA attempted to certify this parameter no fewer than three times with no success. The data indicate that the instrument was only able to compare to the reference method within 30%. This could very well mean that the NOx data presented in the GCA report was in error by as much as 30%. The 0.39 lb/MBtu 30-day NOx

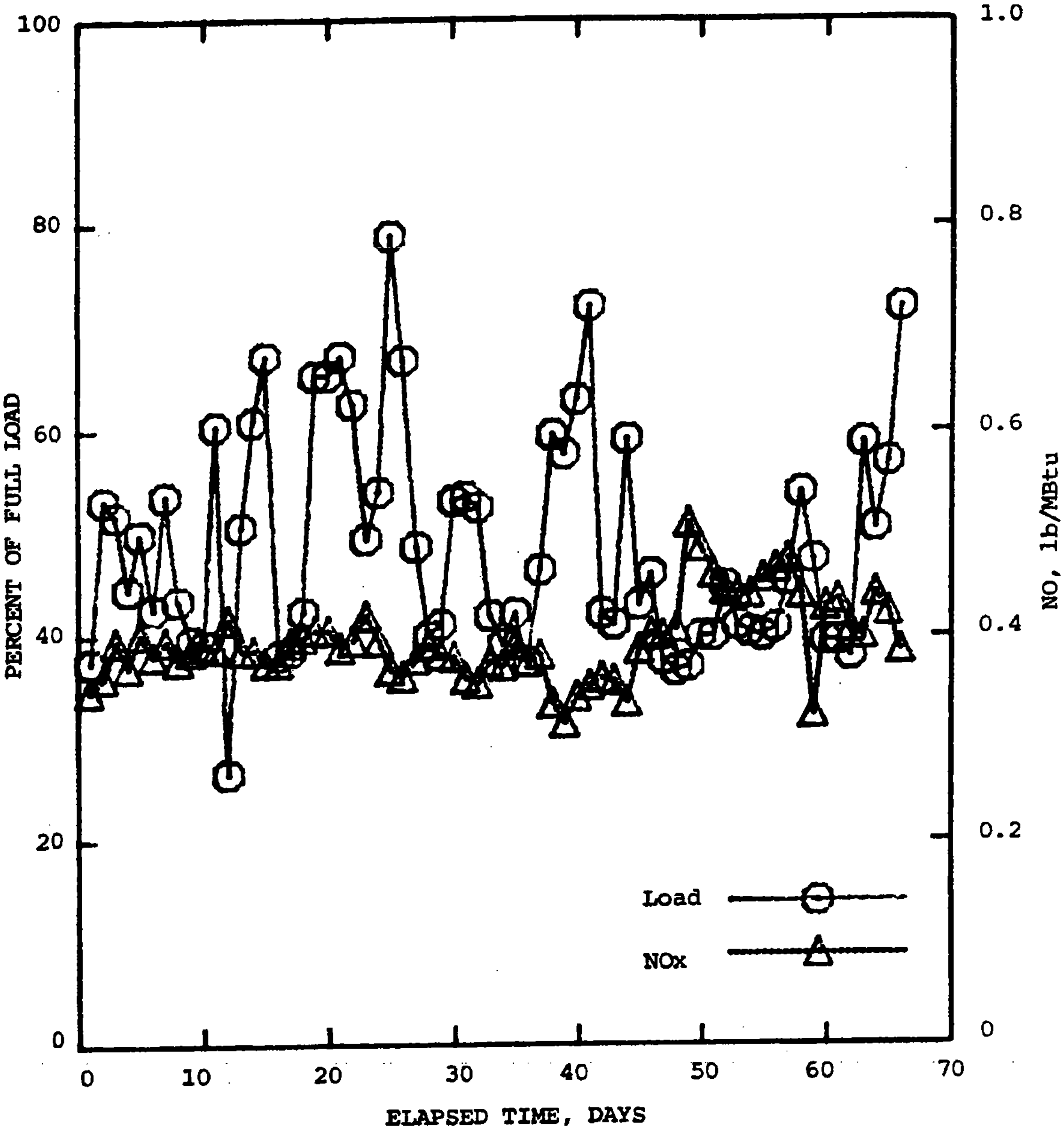

Figure 4-1. A. B. Brown Unit 1, 30-day NOx data (Ref. 2).

TABLE 4-1. COMPARISON OF MONITOR CERTIFICATION DATA (REFS. 2,4)

Test Type	EPA Spec.	Mill Creek Unit 3 Jan.1981	Mill Creek Unit 3 Mar.1981	Homer City Unit 3	A. B. Brown Unit 1
Relative Accuracy	≤20%	17.8	11.52	12.4	23.9(29.0)(26.5)*
Calibration Error					
Mid-Range	≤5%	1.19	0.7	1.6	1.6
High-Range	≤5%	0.71	1.26	4.1	5.6*
Zero Drift					
2-Hour	≤2%	0.034	0.04	0.4	--†
24-Hour	≤2%	0.15	0.145	1.0	0.1
Calibration Drift					
2-Hour	≤2%	0.085	0.155	0.4	--†
24-Hour	≤2.5%	0.280	0.46	0.57	3.3*
Response Time	15 min. max	3.53 min.	0.92	2.4	--§
Operational Period	168 days	168	168	384	--§
Protocol Certification Result		Pass	Pass	Pass	Fail

*Failed EPA certification specification.

†Not performed due to shortage of calibration gases.

§Not supplied.

data could conceivably be as high as 0.51 lb/MBtu. Without the actual certification data, it is difficult to determine the real consequences of the low accuracy obtained on the monitor. One thing that is certain is that it casts serious doubt on the validity of the data and the conclusions that might be drawn from the data.

Notwithstanding the uncertainty of the validity of the data, the data presented in the report yielded some anomalous results which should be pointed out. Figure 4-2 is a plot of the linear regression analysis performed on the daily average NOx values vs. load. The trend from this analysis is that NOx decreases with increasing load. Figure 4-3 is a plot of selected hourly average NOx data vs. load. The data are from the three highest load days and

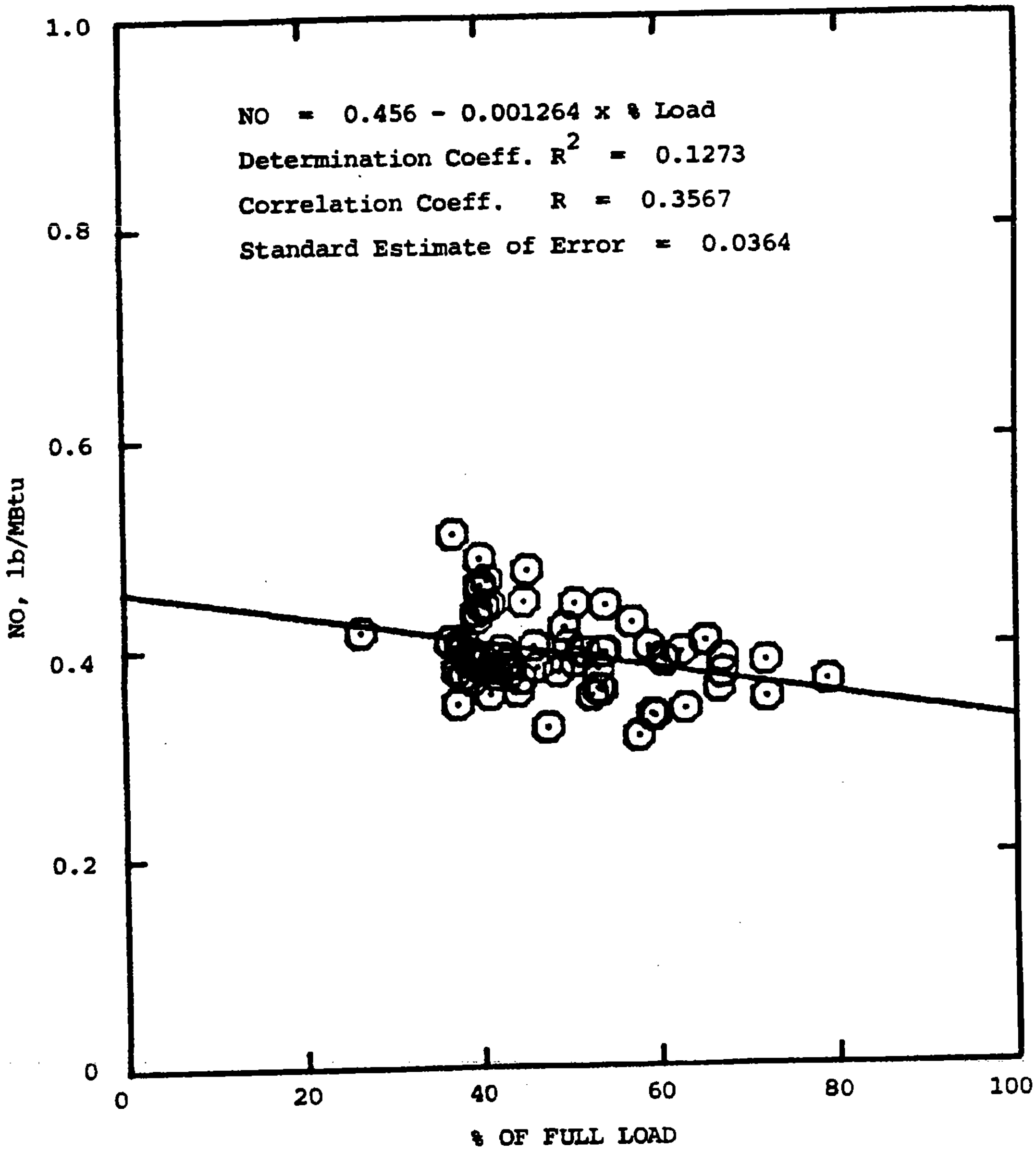

Figure 4-2. Linear regression analysis for A. B. Brown Unit 1 (Ref. 2).

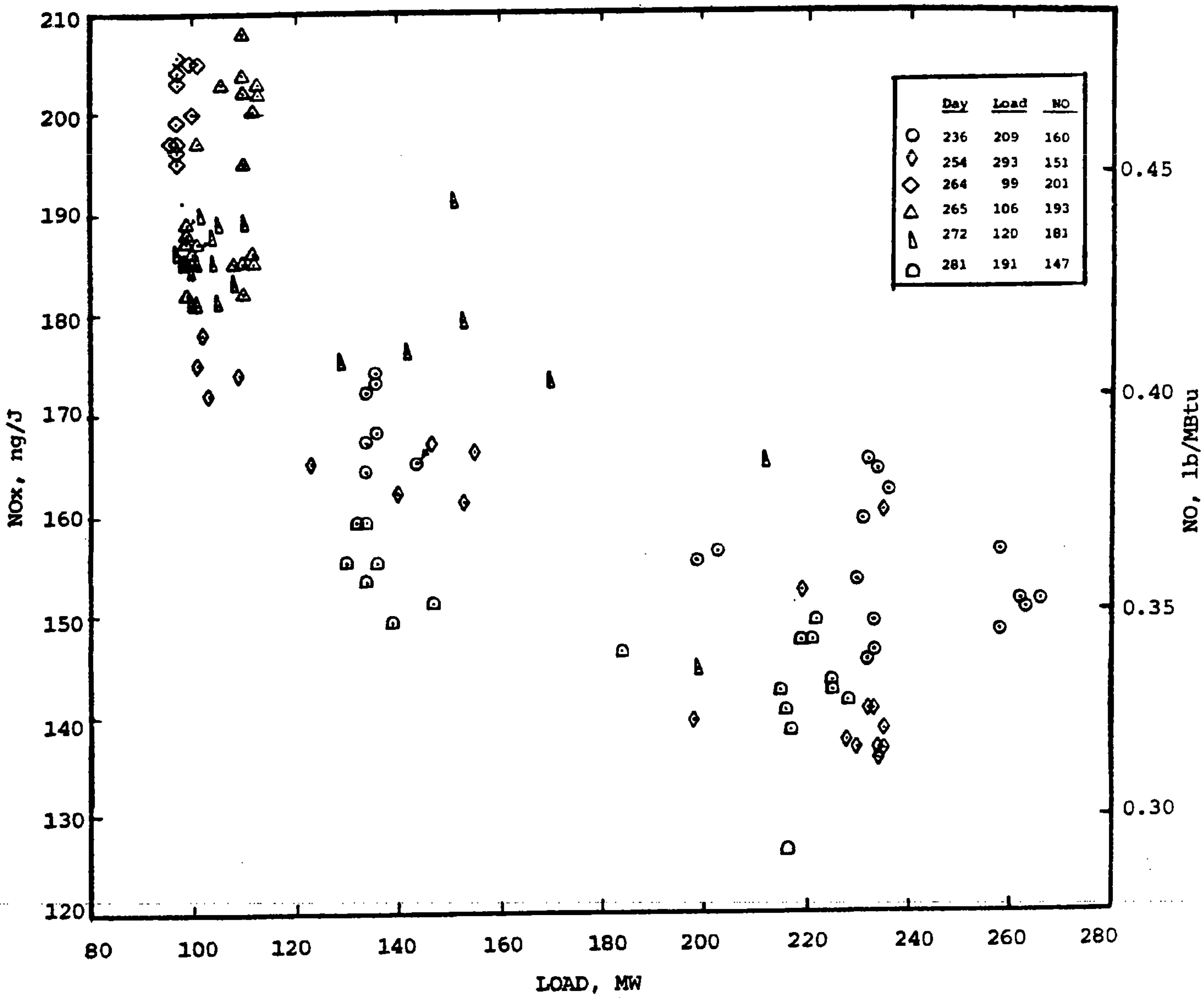

Figure 4-3. A. B. Brown Unit 1 NOx characteristics (Ref. 2).

the three highest 30-day NOx days. The data for the hourly averages shown in Figure 4-2 also suggest that NOx decreases with increasing load. One possible explanation for this trend is that the division walls might effect high load emissions and heat absorption. One could not assume that this NOx vs. load characteristic could be applied to the IGS units, particularly in view of the increasing NOx with increasing load trend of the Mill Creek unit.

Significant anomalies can be seen by inspecting the excess oxygen vs. load curve shown in Figure 4-4. Examination of this data shows two puzzling results--(1) excess oxygen at near full load ranged from 2% to 8% and (2) the general NOx vs. O_2 trend showed decreasing NOx with increasing excess oxygen. The range of excess oxygen level at the 220 to 240 MW range is extremely high; normally the level would be expected to be in the range of 3% to 5%. For example, data for the Mill Creek units in Figure 3-4 show a range from 3% to 5%. In addition, the data for NOx vs. excess oxygen in the 90-110, 130-150, and 210-240 MW ranges generally showed decreasing NOx with increasing excess oxygen level. This is an extremely unusual result and is definitely not characteristic of the majority of boilers. The net result of the brief analysis of these data suggests an atypical characteristic NOx vs. O_2 relationship.

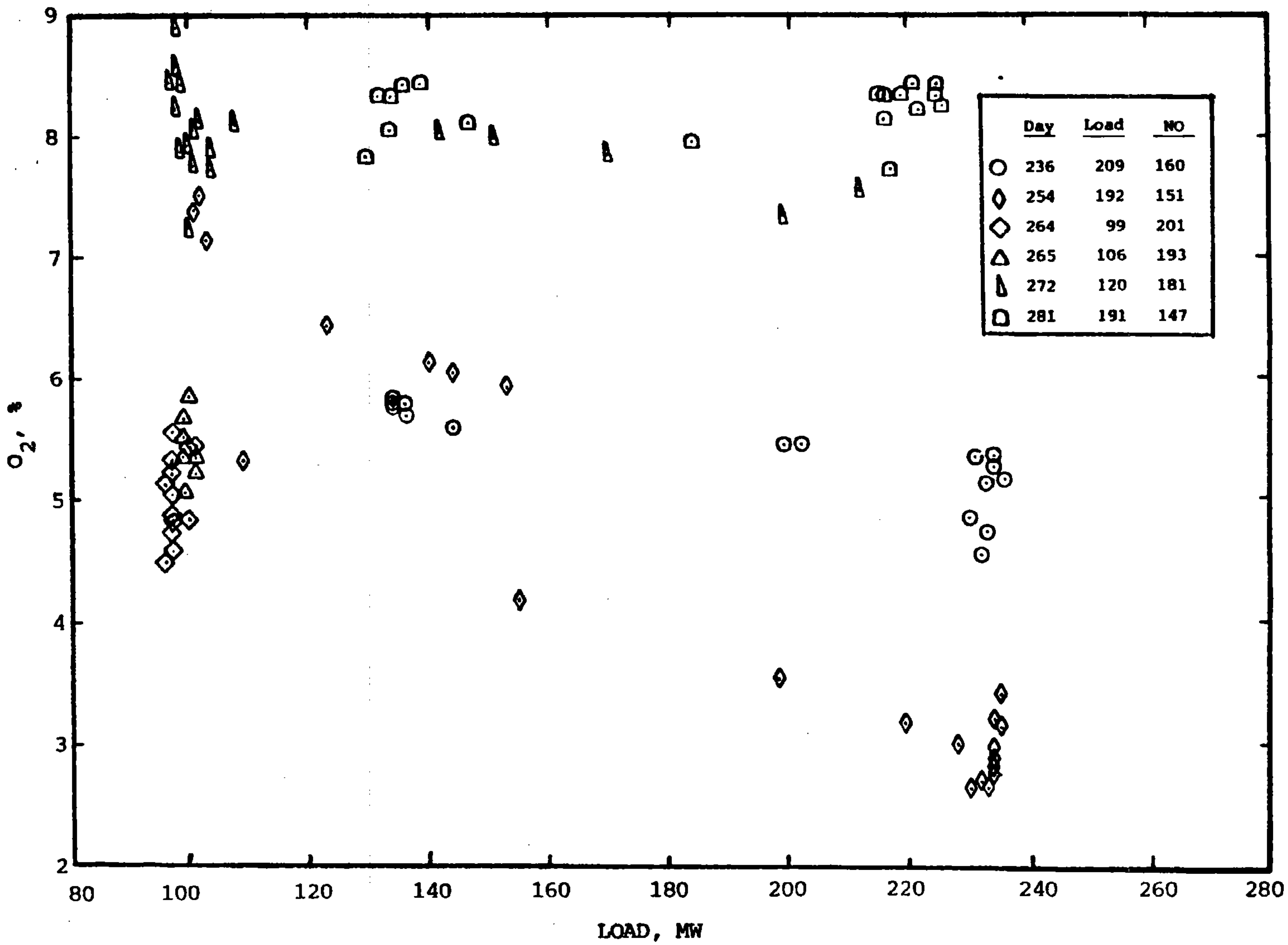

Figure 4-4. A. B. Brown Unit 1 O_2 characteristics (Ref. 2).

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SECTION 5.0

CONCLUSIONS

The overall conclusion that can be drawn from the analysis of the LG&E Mill Creek Unit 3 EPA report (Ref. 1) and the SIGECO A. B. Brown Unit 1 EPA report (Ref. 2) is that the data do not support a NOx limitation lower than 0.550 lb/MBtu on the IGS units. This conclusion is based on the following:

1. No alternate low-NOx modes were demonstrated that would assure reliable long-term operation of either the test units or the IGS units.

2. Thirty-day average NOx data at 68% of full load on the Mill Creek Unit 3 cycling load schedule is not a valid point of comparison for the base loaded IGS units.

3. Simulated high base load conditions using Mill Creek data show 30-day average NOx emissions in excess of 0.550 lb/MBtu.

4. The design of the A. B. Brown unit is not comparable to that of the IGS units since it contains burner zone division walls. The IGS units could not be modified to approximate this design.

5. NOx data from the A. B. Brown unit is not valid due to the lack of adherence to EPA-accepted accuracy criteria. Accuracy errors as high as 30% were indicated.

6. The A. B. Brown unit is characterized by atypical NOx vs. load and NOx vs. O_2 curves. There is little probability that the IGS units would possess similar characteristics.

7. The A. B. Brown unit operated under a severely restrictive cycling load schedule significantly dissimilar to the high base load schedule for the IGS units. The A. B. Brown unit averaged 50% of full load.

Based on these conclusions, the fact that B&W will not guarantee emission levels lower than 0.550 lb/MBtu for the IGS unit design, and the fact that the IGS units will burn high slagging bituminous coal, the present limitation of 0.550 lb/MBtu of NOx is appropriate. The design of the boilers should therefore be considered BACT.

SECTION 6.0

REFERENCES

1. Natanson, P.S., "Long Term Optimum Performance/Corrosion Tests of Combustion Modifications for Utility Boilers," Exxon Research and Engineering, EPA Contract 68-02-2696, Preliminary Draft.

2. Peduto, E. F. et al., "Characterization of the NOx and SO_2 Control Performances: Southern Indiana Gas & Electric Co. A. B. Brown Unit 1," GCA Corporation Report GCA-TR- 82-23-G(1), EPA Contract 68-02-3168, Preliminary, March 1983.

3. Smith, L. L. and Sotter, J. G., "Technical Evaluation of Alternative NOx Control Technologies," KVB Report 38010-2051, June 1983.

4. Cherry, S. S., "Analysis of Long-Term NO Emission Data from Pulverized Coal-Fired Utility Boilers, Volume II, Appendices," KVB Report 34207-1291II, February 1983.

5. Cherry, S. S., "Analysis of Long-Term NO Emission Data from Pulverized Coal-Fired Utility Boilers, Volume I, Technical Analysis," KVB Report 34207-1291I, February 1983.

APPENDIX A

BOILER CHARACTERIZATION TEST SUMMARY
MILL CREEK UNIT 3

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TABLE A-1. SUMMARY OF CONDITIONS TESTED AND RESULTING FLUE GAS ANALYSIS
MILL CREEK UNIT 3 (REF. 1)

TEST	DATE	LOAD	FUELFLOW	KSAIR	INNER	OUTER	SPIN	FGR	FRNGPTRN	BIAS	O2	NOX	NOCHEMI	NONDIR	CO2	CO
1	03/21/79	399	258	7	36	51	10	0	30	0	4.78	450	434	463	15.1	83
2	03/21/79	399	263	3	36	51	10	0	30	0	3.82	402	390	418	15.3	110
3	03/23/79	389	243	7	36	51	10	5	50	0	3.70	343	337	427	15.4	161
4	03/23/79	385	244	3	36	51	10	5	100	6	2.77	316	313	311	15.5	191
5	03/23/79	385	246	7	36	36	10	5	50	0	3.61	349	346	345	15.5	199
6	03/23/79	387	247	3	36	36	10	5	60	6	2.81	327	323	318	15.6	249
7	03/26/79	395	260	7	36	51	10	0	60	6	3.48	394	389	416	15.7	192
8	03/26/79	404	261	3	36	51	10	0	60	6	2.82	361	355	387	15.6	213
9	03/29/79	293	179	7	36	51	10	7	70	0	4.42	534	522	334	15.0	379
10	03/29/79	299	181	3	36	51	10	7	70	6	2.99	280	273	299	15.2	332
11	03/29/79	304	185	7	36	51	10	7	70	6	5.05	294	284	326	14.0	348
12	03/29/79	300	183	7	36	36	10	7	70	6	5.22	289	282	317	13.7	353
13	03/29/79	297	182	7	36	36	10	9	70	0	4.83	308	301	341	13.7	390
14	03/30/79	168	119	7	36	51	10	9	90	0	8.57	297	288	402	13.6	474
15	03/30/79	166	116	3	36	51	10	9	90	0	6.74	230	223	256	13.8	431
16	04/03/79	400	273	7	36	51	10	0	30	0	4.23	415	412	390	15.4	255
17	04/03/79	392	270	7	36	36	10	0	30	0	5.11	455	448	446	15.1	221
18	04/05/79	303	207	7	36	51	10	5	70	0	5.42	375	369	393	14.6	221
19	04/05/79	308	203	5	36	51	10	5	70	0	4.55	348	346	371	14.4	201
20	04/05/79	326	216	7	36	71	10	5	70	0	4.54	365	360	390	14.2	184
21	04/05/79	325	218	7	36	51	10	5	70	0	4.24	358	353	380	14.1	178
22	04/05/79	326	216	5	36	71	10	5	80	6	4.17	353	347	368	13.8	159
23	04/06/79	197	136	7	36	51	10	9	70	0	6.56	320	314	517	14.6	323
24	04/06/79	203	142	6	36	51	10	9	80	6	6.01	312	302	341	14.0	272
25	04/06/79	204	135	6	36	71	10	9	80	6	6.03	289	283	311	13.9	251
26	04/06/79	199	143	6	36	36	10	9	80	6	5.77	286	279	315	14.1	260
27	04/07/79	407	277	7	36	51	10	4	50	0	4.45	399	392	404	15.1	18
28	04/07/79	409	277	7	36	36	10	3	50	0	4.41	414	408	442	13.7	20
29	04/07/79	408	272	7	36	71	10	3	50	0	3.96	408	402	466	13.5	19
30	04/07/79	404	273	3	36	71	10	3	60	6	3.58	398	391	476	13.4	19
31	04/07/79	404	271	3	36	36	10	3	60	6	3.43	382	373	468	13.4	19
32	04/07/79	402	272	7	36	51	10	3	70	0	4.60	457	450	457	14.1	14
33	04/07/79	400		7	36	71	10	3	70	0	4.44	440	433	437	13.9	13
34	04/07/79	402		3	36	71	10	3	80	6	4.01	399	390	321	14.3	19
35	04/07/79	401		3	36	51	10	3	80	6	3.97	400	392	325	14.5	11
36	04/09/79	308	207	7	36	51	10	0	70	0	4.82	366	363	389	14.7	44
37	04/23/80	175		7				0		0	11.02	352	363	425	14.1	641
38	04/23/80	251	219	7				0	30	0	6.22	304	301			598
39	04/23/80	392	337	7				0	30	0	5.80	379	375			628
40	10/08/80	400	346	7	44	29	23	0	30	0	5.69	517	512		15.6	15
41	10/08/80	400	334	3	44	29	23	0	30	0	6.48	503	493		16.1	92
42	10/08/80	410	336	7	44	29	23	0	50	0	4.52	466	463		16.3	21
43	10/08/80	405	335	3	44	29	23	0	50	0	3.13	415	603		24.6	343
44	10/08/80	402	340	3	44	29	23	0	70	0	5.31	507	503		16.0	20
45	10/08/80	401	334	3	44	29	23	0	70	0	4.15	461	461		16.3	175
46	10/09/80	403	321	7	44	29	23	0	70	0	5.11	515	512		16.2	22
47	10/10/80									LEAK						
48	10/10/80	399	300	7	44	29	23	5	70	0	10.20	467	486		14.9	138
49	10/15/80	418	353	7	44	29	23	0	70	0	4.82	494	493		15.1	74

KEY TO ABBREVIATIONS: See next page.

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KEY TO ABBREVIATIONS USED IN TABLE A-1

LOAD:	Megawatts (net)
FUEL FLOW:	Coal flow ... kPounds/hour
XSAIR:	Qualitative description (on a scale of 1 to 9) of the amount of excess air delivered to the combustor. 1: Much less excess air than normal ——— (< ∿4% O_2) 7: Normal (Note that normal is 7, not 5) ——— (∿4% O_2) 9: More excess air than normal ——— (> ∿4% O_2)
INNER OUTER SPIN } :	Each has units of "percent of full open". Describes the average positions of the burner vane and register controls.
FGR:	A qualitative description of the amount of flue gas being recirculated to the hopper. 0: None (FGR fan off) 9: High (fan on and dampers open)
FRNGPTRN:	Firing pattern is a qualitative term (on a scale of 0 to 100) for describing how the total fuel flow is distributed among the several rows of burners. The higher the valve, the lower is the fraction of the total fuel flow in the upper burners. It is expected that high "FRNGPTRN" values will result in low NO_x. 0: All bottom burners are off 50: All burners are on equally 100: All top burners are off
BIAS:	Describes the way the air fuel ratio varied from burner row to burner row. High bias was expected to give low NO_x. 0: All burners had the same air fuel ratios (no bias) 9: High bias. Air/fuel ratio is much higher in upper burners than in bottom ones.
NOXCHEMI:	NO_x (as measured by the chemiluminescent method) has units of ppm(v) @ 3% O_2, dry.
NOCHEMI:	NO (as measured by the chemiluminescent method) has units of ppm @ 3% O_2, dry.
NONDIR:	NO_x (as measured by the nondispersive infra-red method) has units of ppm @ 3% O_2, dry.
CO_2:	percent @ 3% O_2, Dry.
CO:	ppm @ 3% O_2, Dry.

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TABLE A-2. SUMMARY OF TEST CONDITIONS FOR MILL CREEK UNIT 3
GROUPED BY TEST CONDITIONS (REF. 1)

Firing Mode	Bias	Full Load (>400 MW) Normal Air 35	Full Load Normal Air 50	Full Load Normal Air 70	Full Load Low Air 35	Full Load Low Air 50	Full Load Low Air 70	Medium Load (300 MW) Normal Air 35	Medium Load Normal Air 50	Medium Load Normal Air 70	Medium Load Low Air 35	Medium Load Low Air 50	Medium Load Low Air 70	Low Load (<200 MW) Normal Air 35	Low Load Normal Air 50	Low Load Normal Air 70	Low Load Low Air 35	Low Load Low Air 50	Low Load Low Air 70
All Burners On	No	5N 28N 42N	3L 27M	29N	43N														
All Burners On	Yes		7N		6L 31N	4L 8N	30N												
One Top Mill Off	No	44N 46N 48H 49N	32N	33N	45N			13M	9L 18L 21L 36N	20L		19L							
One Top Mill Off	Yes					35N	34N	12M	11M			10L	22L						
One Bottom Mill Off	No	17N 40N	1N 16N 39N**		41N	2N			38N**										
One Bottom Mill Off	Yes																		
Both Top Mills Off	No														14H 23H			15H	
Both Top Mills Off	Yes													26H	24H	25H			

*Letter suffixes refer to amount of flue gas recirculation (None, Low, Medium, High - as explained on next page).
**The damper positions for Tests 38 and 39 were not recorded.

For additional notes, see next page.

NOTES FOR TABLE A-2

FLUE GAS RECIRCULATION (KEY TO LETTER SUFFIXES)

- During some tests, flue gas was recirculated to the hopper. The amount of Flue Gas so recirculated is qualitatively indicated by a letter suffixed after each test number in Table B-III-2. The letters stand for: None, Low, Medium, and High.

EXCESS AIR (LIMITS OF CONTROL SYSTEM)

- For low excess air tests, the air flow was decreased first on the bottom mills by going to full range on the bias thumb-wheel control. Then, if further decrease in excess air was desired, the boiler master control was used. However, if air was decreased beyond a certain preset limit on any one mill, the automatic control system would decrease the fuel flow to keep the fuel/air ratio within preset limits and a load reduction would result. This was an undesirable situation, and was avoided by the operators.

BIAS CONTROL SYSTEM

- Bias was generally controlled through the fuel/air bias control thumb-wheel on each mill controller while still in automatic control. Under these conditions, the amount of bias possible was quite small. The following is a qualitative description of the terms used to describe whether or not (yes or no) biased fuel/air ratios were used during each test.

  No = Little or no Bias

  (i.e., Fuel/air ratios were nearly equal for all burners.)

  Yes = Significant Bias

  (i.e., Upper burners have significantly smaller fuel/air ratios than lower burners.)

APPENDIX B

HIGH LOAD HOURLY AVERAGE DATA
MILL CREEK UNIT 3

TABLE B-1. MILL CREEK UNIT 3 HIGH LOAD
HOURLY AVERAGE NOx DATA (REF. 4)

Day	Hour	Load MW	O_2 %	NOx lb/MBtu	Day	Hour	Load MW	O_2 %	NOx lb/MBtu	Day	Hour	Load MW	O_2 %	NOx lb/MBtu
4	7	399	4.0	0.543	16	12	396	4.8	0.606	18	11	397	4.8	0.550
4	8	423	3.1	0.590	16	17	396	5.4	0.548	18	12	423	4.0	0.542
4	9	414	3.8	0.630	16	18	395	5.2	0.622	18	13	424	4.0	0.527
4	10	399	5.0	0.576	16	19	398	5.3	0.619	18	14	395	4.0	0.513
4	11	399	5.0	0.586	16	20	395	5.3	0.617	18	15	400	4.1	0.502
4	12	415	4.8	0.550	16	21	395	5.2	0.598	18	16	398	4.2	0.509
5	10	400	5.0	0.480	17	8	393	6.3	0.580	18	17	397	4.1	0.492
5	13	397	4.4	0.543	17	10	397	5.2	0.566	18	18	399	4.1	0.492
5	14	400	4.3	0.512	17	11	397	5.3	0.585	18	19	399	4.1	0.508
15	9	392	5.3	0.548	17	13	395	4.9	0.560	18	20	395	4.1	0.507
15	10	394	5.3	0.598	17	14	397	4.8	0.557	18	22	394	4.2	0.497
15	12	410	4.9	0.588	17	18	397	4.8	0.549	23	16	397	3.7	0.477
15	13	425	4.3	0.542	17	19	397	4.8	0.550	23	17	394	3.9	0.467
15	14	408	4.1	0.541	17	20	397	4.9	0.540	23	18	397	3.9	0.483
15	15	408	4.2	0.524	17	21	397	4.9	0.553	23	19	395	4.0	0.494
15	16	412	4.1	0.527	17	22	394	4.9	0.556	24	8	394	4.0	0.522
15	17	409	4.0	0.535	17	23	393	4.9	0.556	24	9	403	3.9	0.561
15	18	408	4.1	0.531	18	4	395	5.0	0.581	24	10	413	3.8	0.551
15	19	414	4.2	0.542	18	5	395	5.0	0.590	24	12	410	3.3	0.491
15	20	416	4.2	0.552	18	6	395	5.1	0.601	24	13	412	3.2	0.500
15	21	415	4.2	0.561	18	7	407	5.0	0.613	24	14	416	3.3	0.512
15	22	410	4.2	0.559	18	8	398	4.9	0.603	24	15	394	4.0	0.535
16	10	393	4.5	0.554	18	9	397	4.9	0.588	24	16	394	4.5	0.561
16	11	395	5.1	0.585	18	10	403	4.9	0.570	24	17	396	4.5	0.574

(continued)

Mill Creek Unit 3 Data (Cont.)

Day	Hour	Load MW	O_2 %	NOx lb/MBtu	Day	Hour	Load MW	O_2 %	NOx lb/MBtu	Day	Hour	Load MW	O_2 %	NOx lb/MBtu
24	18	402	4.6	0.568	30	9	407	5.9	0.544	54	9	394	4.4	0.527
24	21	394	4.7	0.560	30	10	411	4.2	0.520	54	10	404	4.7	0.548
25	7	394	4.3	0.555	30	11	406	4.3	0.530	54	11	407	5.3	0.600
25	8	399	4.2	0.551	33	10	399	5.8	0.551	54	12	398	4.8	0.538
25	9	400	4.2	0.555	33	11	401	6.0	0.560	54	16	392	5.2	0.605
25	10	394	4.1	0.555	33	12	396	4.9	0.552	55	16	392	5.2	0.605
25	13	396	3.8	0.537	33	13	393	4.8	0.520	55	21	392	5.2	0.605
25	14	403	3.7	0.551	33	14	392	6.8	0.530	56	11	398	5.6	0.571
25	15	402	3.6	0.537	33	18	392	5.5	0.577	56	16	392	5.0	0.583
25	16	400	3.6	0.520	35	9	392	4.7	0.551	56	21	393	5.0	0.577
25	17	400	3.7	0.517	36	9	399	4.6	0.605	57	10	394	5.3	0.582
25	18	409	3.7	0.530	40	14	394	4.1	0.567	57	11	397	4.6	0.569
25	19	408	4.0	0.541	40	15	392	4.0	0.560	57	16	393	4.4	0.526
25	20	401	4.0	0.541	40	20	394	4.5	0.584	57	20	392	4.8	0.573
25	21	401	4.1	0.526	41	21	392	4.5	0.582	57	21	392	4.7	0.559
25	22	400	4.1	0.529	42	10	393	4.5	0.588	57	22	393	4.7	0.565
25	23	394	4.4	0.528	42	13	392	4.1	0.587	58	10	392	4.7	0.547
26	7	394	5.0	0.492	42	15	393	4.0	0.522	58	11	394	4.5	0.533
26	8	393	5.1	0.552	42	20	395	4.4	0.573	58	13	394	4.6	0.544
26	9	395	5.0	0.545	42	21	393	4.3	0.573	58	14	395	4.4	0.545
27	9	396	5.5	0.591	43	20	393	4.1	0.547	58	15	393	4.4	0.547
27	10	395	5.4	0.605	50	14	395	5.2	0.566	58	17	392	4.5	0.548
29	12	393	5.5	0.524	50	15	393	5.3	0.602	58	18	392	4.5	0.549
29	13	398	5.4	0.524	50	20	394	5.3	0.585	58	20	400	4.5	0.544
30	8	409	4.4	0.463	50	21	393	5.4	0.612	58	21	392	4.4	0.544

(continued)

Mill Creek Unit 3 Data (Cont.)

Day	Hour	Load MW	O_2 %	NOx lb/MBtu	Day	Hour	Load MW	O_2 %	NOx lb/MBtu	Day	Hour	Load MW	O_2 %	NOx lb/MBtu
58	23	393	4.6	0.556	62	17	399	4.0	0.578	63	19	397	4.1	0.581
59	16	393	5.3	0.623	62	18	394	4.0	0.571	63	20	396	4.1	0.576
59	17	396	5.3	0.627	62	19	397	4.1	0.569	63	21	395	4.0	0.573
59	18	396	5.1	0.615	62	20	401	4.1	0.582	63	22	396	4.1	0.580
59	20	393	5.8	0.634	62	21	396	4.1	0.586	64	8	397	4.7	0.588
59	21	394	5.8	0.642	62	22	392	4.2	0.569	64	9	398	4.6	0.594
59	22	394	5.7	0.628	63	7	398	4.5	0.545	64	10	396	4.5	0.582
61	11	392	4.6	0.481	63	8	398	4.2	0.562	64	12	396	4.7	0.590
61	21	397	5.3	0.643	63	9	399	4.0	0.570	64	13	379	4.8	0.585
61	22	394	5.3	0.643	63	10	396	4.0	0.577	64	14	401	4.1	0.522
62	8	393	6.0	0.615	63	12	396	4.1	0.560	64	15	402	3.8	0.519
62	9	392	5.4	0.592	63	13	396	4.1	0.566	64	16	398	3.9	0.507
62	10	394	5.3	0.578	63	14	397	4.1	0.564	64	17	394	3.8	0.501
62	11	393	4.7	0.555	63	15	395	4.1	0.572	64	20	395	4.7	0.565
62	13	395	4.7	0.558	63	16	396	4.2	0.583	64	21	394	4.2	0.559
62	15	392	4.3	0.518	63	17	396	4.1	0.584	64	22	396	3.9	0.505
62	16	400	4.5	0.576	63	18	397	4.1	0.578	64	23	392	3.9	0.512

TABLE B-2. MILL CREEK UNIT 3 HOURLY AVERAGE DATA FOR SIMULATED HIGH LOAD 30-DAY ROLLING AVERAGE NOx

Simulated Day	8-Day Data Input (From Table B-1)			
	From		To	
	Day	Hour	Day	Hour
1	4	7	16	11
2	16	12	18	10
3	18	11	24	17
4	24	18	29	12
5	29	13	50	14
6	50	15	58	17
7	58	18	62	20
8	62	21	64	15
9	64	16	64	23
	4	7	15	18
10	15	19	18	4
11	18	5	24	10
12	24	12	25	23
13	26	7	42	10
14	42	13	57	22
15	58	10	62	13
16	62	15	64	8
17	64	9	64	23
	4	7	15	12
18	15	13	17	18
19	17	19	23	16
20	23	17	25	17
21	15	18	33	18
22	35	9	56	22
23	57	10	61	21
24	61	22	63	17
25	63	18	4	12
26	5	10	16	21
27	17	8	18	16
28	18	17	33	10
29	25	9	33	10
30	33	11	54	11

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